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DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MONTANA

IN THE MATTER OF Inquiry by the Montana Public Service Commission into its Implementation of the Public Utility Regulatory Policies Act of 1978	))))	**INITIAL COMMENTS OF LEO WIND, LLC** Docket No. N2015.9.74

INTRODUCTION

LEO Wind, LLC ("LEO"), and Hydrodynamics, Inc. ("Hydrodynamics"), acting by and through undersigned counsel, hereby submit their initial comments pursuant to the Commission's notice of inquiry in this Docket. LEO and Hydrodynamics hereby submit their comments in response to the Staff Memorandum prepared on August 11, 2015. Hydrodynamics also submits its own separate draft comments attached to these comments. *See* Exhibit 1, hereto. At the outset, LEO and Hydrodynamics wish to express the importance of this inquiry, and that the Montana Public Service Commission ("Commission") to carefully consider these comments. LEO and Hydrodynamics wish to emphasize that their collective view is that, in the past, the Commission has adopted rules and decisions which were inimical to the proper implementation of the Public Utility Regulatory Policies Act of 1979, 16 U.S.C. § 824-a3 *et seq* ("PURPA"). Such rules and decisions include A.R.M. § 38.5.1902(5) which on its face does not permit qualifying facilities or "QFs" under PURPA that have an installed capacity larger than the current 3 megawatt ("MW") threshold for a standard offer rates to create a legally enforceable obligation or "LEO." The unfairness of this Commission rule led Hydrodynamics, among others, to file a petition for enforcement and declaratory order with the Federal Energy Regulatory Commission ("FERC"). FERC declined to take enforcement action against the PSC, but FERC found in favor of Hydrodynamics and the other petitioners in that case, stating that A.R.M. § 38.5.1902(5) was inconsistent with FERC's regulations implementing PURPA, an unreasonable implementation of PURPA, and a practical disincentive to amicable contract formation between QFs and Montana utilities. *Hydrodynamics, Inc., Montana Marginal, Inc. and WINData, LLC,* 146 FERC ¶ 61,193, PP. 30-32 (March 20, 2014). FERC stated:

> In *Grouse Creek*, the Commission found that the Idaho Commission's requirement that a QF file a meritorious complaint to the Idaho Commission before obtaining a legally enforceable obligation "would both unreasonably interfere with a QF's right to a legally enforceable obligation and also create practical disincentives to amicable contract formation. Similarly, we find that requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation particularly where, as here, such competitive solicitations are not regularly held.

Id. at P. 32.

Although Greycliff Wind Prime, LLC, has formally requested that A.R.M. § 38.5.1902(5) be repealed or amended, that process is as yet complete and NorthWestern Corporation d/b/a NorthWestern Energy ("NWE") has continued to use the existence of this rule as a reason not to enter into amicable contract discussions with QFs. *See* Exhibit 2 to Greycliff Wind Prime, LLC's Petition to Set Contract Terms and Conditions Pursuant to M.C.A. § 69-3-603 in Docket D2015.8.64. Regardless, the policy questions posed by the Commission staff in its August 11, 2015 memorandum raise other questions which are equally important to the implementation of PURPA in Montana.

I. POSSIBLE METHODS FOR ESTIMATING AVOIDED COST

The Commission posed the following questions after a general discussion of the proposed methods for calculating avoided cost:

a) What methods are reasonable for the Commission to use to estimate NWE's long-term avoided costs and set rates for small and large QFs? Why are those methods preferred?

LEO and Hydrodynamics would prefer an avoided cost methodology based either on the utility's assets or on market, but not on both. All too often this results in a "heads the utility wins, tails the QFs lose" approach. If the incremental costs of a surrogate plant are used, the avoided capital and energy costs associated with that next planned unit should not be pushed years into the future whereby the avoided capital costs and energy costs are assumed to be reflective of nominal inflation in energy prices. On-peak and off-peak assumptions, both as a planning matter, and as an avoided cost matter, need to be scrutinized and considered more closely should the Commission base avoided cost on a realistic assessment of utility planning needs into the future.

If a market assessment is utilized by the Commission, the Commission needs to take into account a realistic assessment of a utility's reliance on market power, and whether it has appropriate planning margin needs to be included in any market-based assessment. This would necessarily include planning assumptions based on what other utility and reliability organizations are recommending and implementing outside of the NWE balancing authority. In particular, the cost of regulation has suffered from a lack of transparency, apparent disputes over whether and when to include the fixed and variable costs in the wind integration tariff, and the costs of wind integration from Dave Gates Generating Station ("DGGS") as opposed to third party supply of integration. Too often, NWE has resisted implementing positive changes that would result in increased reliability and stability in its balancing authority, and the Commission to date has not required an inclusion by NWE of those practices or recommendations in either its planning or its QF-1 standard rate or the cost of providing regulating reserves.

That said, the method utilized by the Commission currently is not inherently unfair or discriminatory provided: (1) the Commission is open to revisiting the utility's planning assumptions; (2) the Commission requires NWE to adhere to the methodology such that it does not, as has recently been the case in Dockets D2014.1.5 and D2012.1.3, result in NWE implementing the methodology in a manner inconsistent with prior Commission orders; and (3) a realistic assessment is made with respect to whether NWE discriminates in its own favor in resource acquisition decisions and whether the rates NWE is paid for its own investment mirrors or approximates what it reports to the Commission in its similarly biennial Electricity Supply Resource Procurement Plans. Too often what is in NWE's Electric Supply Resource Procurement Plans is inconsistent with NWE's avoided cost proposals.

b) What methods should the Commission refrain from using to estimate NWE's long-term avoided costs and set rates for small and large QFs. Why should those methods be avoided?

LEO and Hydrodynamics urge the Commission not to adopt avoided cost methodologies which will require a considerable amount of investment in modeling, and which are transparent rather than opaque. As long as the inputs and results from a differential revenue requirement methodology are made available without cost to the Commission and all parties, LEO and Hydrodynamics believe it may prove to be a superior methodology. However, most QFs have limited budgets for legal and expert assistance, and requiring a QF to go through the cost and expense of acquiring a model and engaging in lengthy discovery disputes over inputs and assumptions in the model automatically results in a disadvantage to QFs. Unlike NWE, QFs must bear its own legal and expert costs, and this asymmetry would result in an uneven playing field.

c) Does NWE's acquisition of the PPLM hydroelectric resources affect which methods are best suited for estimating NWE's avoided costs? If so, how?

Since NWE's acquisition of the PPLM hydroelectric resources, the question of whether and how this acquisition would affect different avoided cost calculation methods has not been studied. Presumably, it would affect each type of methodology in differing ways. For example, NWE will likely adjust capacity and energy avoided costs based on the existence of the PPLM hydroelectric resources in its portfolio. However, since NWE has already acquired the PPLM hydroelectric resources, those costs are no longer "avoidable," and while the existence of those plants affect NWE's planning, they may or may not affect NWE's avoided costs. The question of whether NWE may be required to accept QF generation in lieu of its own generating resources was recently addressed, albeit somewhat obliquely, by FERC in the *Idaho Wind Partners I, LLC* order regarding the applicability of utility "light loading curtailments" to QFs which are selling pursuant to long-term fixed obligations. 140 FERC ¶ 61,219, PP 40-41. Utilities can be forced to back down base load generation in order to accommodate purchases from QFs, and as a planning matter, this should be taken into account by the Commission, NWE, and other Montana utilities.

d) Is NWE's PowerSimm planning model suitable for applying differential revenue requirements and component/peaker methods? What, if any, concerns would you have with using PowerSimm to estimate avoided costs using these methods?

LEO and Hydrodynamics reiterate the concerns about the use of opaque and less than transparent methods of calculating avoided costs expressed in response to Section I (c) above. LEO and Hydrodynamics understand that in the Matter of NorthWestern Energy's petition to set contract terms and conditions with Greenfield Wind, LLC, in Docket D2014.4.43, disputes arose about the inputs and access to the PowerSimm model. Regardless, use of such a method of calculating avoided costs would be acceptable provided that the cost of accessing the model and its inputs is not prohibitively expensive or there are not substantial other barriers to utilizing it in a fair and non-discriminatory basis. PowerSimm is like any other model, the inputs that are used greatly affect the output, and fair and equal access to the model and its inputs are necessary to ensure a level playing field.

e) **If PowerSimm is suitable for applying differential revenue requirements and component/peaker methods, does the model need to make use of optimal capacity expansion planning capabilities in order to reasonably calculate applicable costs? Why or why not?**

LEO and Hydrodynamics are unsure as to what the Staff means by "optimal capacity expansion capabilities," but if the question means to ask whether or not PowerSimm should model the ideal path for capacity expansions, the answer is it depends on whose idea of "optimal." LEO and Hydrodynamics presume the QF community, the Montana Consumer Counsel, and the utilities may differ greatly on the assumptions which underpin the term "optimal." That said, in principle, LEO and Hydrodynamics believe that should be the goal of the process, but that the path to reaching that goal may take very different roads depending upon the assumptions and views of each interested party.

II. Standard Rate Design

a) Should the Commission set separate standard rates for small solar, hydroelectric, and/or other eligible generating technologies that reflect the specific generating characteristics of those technologies? Why or why not?

LEO and Hydrodynamics believe FERC has made clear that the Commission may, but is not required to adopt different avoided cost rates for different types of projects. LEO and Hydrodynamics believe that such differential rates would create incentives for the development of different generating technologies which may add diversity and better operational characteristics for utility system operators such as NWE. The cost of different types of generating technologies varies, particularly in the capacity cost component. Creating incentives for these new technologies may create a stronger overall utility generation portfolio.

b) What contract length is sufficient to enable a viable QF project to obtain financing?

LEO and Hydrodynamics believe a 20-year contract length is the minimum, and that 25 years would be better. Typically speaking, longer contract terms permit a project to pay off debt service over a longer period of time, thus enabling a project to earn some return on its investment earlier. Since the adoption of PURPA, FERC has repeatedly evinced the concern that QFs be able to lock in long-term rates so as to be able to evaluate the financial viability of a project. *See e.g., JD Wind 1, LLC*, 130 FERC ¶ 61,127, at P 23 (February 19, 2010) Docket EL09-7701 (Order Denying Requests for Rehearing, Reconsideration or

Clarification). Therein, the Commission stated unequivocally that it was concerned about the ability of an investor to determine the long-term return on its investment:

> The Commission's regulations, from the beginning, have given QFs the option of choosing to have rates calculated at the time the obligation is incurred. The intention of the Commission was to enable a QF "to establish a fixed contract price for its energy and capacity at the outset of its obligation." The Commission recognized that:
>
> [I]n order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.

Citing *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978,* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,868 (1980), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part and vacated in part*, *American Electric Power Service Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part*, *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402 (1983)("Order No. 69"). In other words, Order 69 has always encouraged the use of long-term contracts so as to encourage QF generation. This same policy is expressed in M.C.A. § 69-3-604(2), which expressly states: "Long-term contracts for the purchase of electricity by the utility from a qualifying small power production facility *must be encouraged in order to enhance the economic feasibility* of qualifying small power production facilities." (Emphasis added). In other words, the length of the contract must enable a QF to be economically feasible. This means a financing term that allows investors in the project and to pay off debt service over a longer-term. LEO and Hydrodynamics are unaware of any QF projects financed on a 15-year term, and all are typically financed over a 20-year or 25-year term. This is also generally consistent with how utilities finance their own long-term capital investments.

c) Does a 25 year standard rate contract length impose undue forecast risk on consumers? If so, why?

There is always risk associated with any long-term contract, whether it is a utility owned asset or a power purchase agreement. Avoided cost calculations are at best an imperfect science. However, there is an asymmetrical risk posed by utility investment in plant on the one hand, and long-term power purchase agreements with QFs. The utility may, if its asset underperforms, request from the Commission an increased cost recovery from that facility. QFs must live with their agreements, and if their asset underperforms, are stuck with the financial and contractual consequences of their decisions. It is notable that many proposed QF contract from the early 2000's, such as the Whitehall Wind project, which the Commission rejected in 2002, proposed rates in the low $30/MWH range which would be a bargain for consumers today.

d) Comment on the reasonableness of shortening the maximum contract length in NWE's standard QF tariff schedules.

As noted above in response to II (b), the standard contract length should reflect the lending and financing practices of debt and equity investors for QFs and for utilities. Shortening the length of these agreements to less than 20 or 25 years would be punitive and unreasonable for small QFs.

e) To what extent should the length of a standard rate QF contract reflect the economic life of alternative resources NWE is planning to acquire?

As discussed in Section I, above, regarding methodology, the useful life of economic resources should be utilized in calculating avoided cost rates, but should not be used for legal, financial, and practical reasons.

f) Should standard rates reflect avoided costs levelized for the length of the contract? Why or why not?

LEO and Hydrodynamics believe levelized costs encourage financing and allow investors to earn a reasonable return in the early years of the power purchase agreement with the utility. If a QF can obtain financing without utilizing a levelized rate, that should be at its option. However, the QF should have the option for levelized rates in order to encourage the development and investment in QF technologies.

g) Montana law requires the Commission to encourage long-term contracts for purchases of electricity by utilities from QFs. Mont. Code Ann. § 69-3-604(2). How should the Commission interpret or define "long-term"?

LEO and Hydrodynamics discussed this issue previously in response to Section II (d). The answer is the length that is typically used to fund long-term capital investments by both QFs and utilities, such that it encourages investment in these technologies according to FERC Order 69 and M.C.A. § 69-3-604(2).

h) Should standard rates include performance standards and automatic rate adjustments for failure to meet the standards? Provide any specific recommendations you have for such standards and rate adjustments.

LEO and Hydrodynamics generally believe such adjustments would be unlawful and an interference with FERC's prerogatives in certifying qualifying facilities. *Independent Energy Producers Ass'n v. California Pub. Utils. Comm'n,* 36 F.3d 848, (9th Cir. 1994) (finding state program for determining whether QFs were complying with their certifications exclusively the province of FERC). In addition, regulatory "opt out" clauses which permitted rate adjustments during the life of the contract could not be imposed on QFs by state regulatory commissions. *E.g., Freehold Cogeneration Assocs., L.P. v. Board of Regulatory Comm'rs,* 44 F.3d 1178, (3d Cir. 1995). Notwithstanding the foregoing, the terms "performance standards" and "rate adjustments" are not clearly defined, and as such, without knowing more LEO and Hydrodynamics cannot meaningfully comment upon them subject to the foregoing federal circuit court authorities.

i) Should the Commission approve a full standard power purchase agreement? Why or why not?

LEO and Hydrodynamics believe that the standard offer contracts, currently available only to QFs with an installed capacity of 3 MW or less, are needed. A 3 MW project consists of likely one turbine. These projects have a lesser ability to take advantage of economies of scale. Negotiating power purchase agreements with utilities which such a small revenue stream imposed undue and unfair burdens on such projects. Having a public process where the terms can be fully and fairly debated by all interested stakeholders, with the aim of producing a fair and reasonable standard contract, would benefit these small QFs by reducing transaction costs. It would also reduce consumption of scarce Commission resource by reducing case-by-case disputes over new contract terms a utility may attempt to impose on a on a single QF, which the utility may then use as contracting precedent by future QFs. This gamesmanship potential would be eliminate by the Commission's adoption of standard QF contracts for projects with an installed capacity of 3 MW or less.

Furthermore, LEO and Hydrodynamics, feel standard draft contracts should be offered to any party on request, and that contract negotiations should continue with all QF projects regardless of their position in a 'queue'. As noted above, contract negotiation is no small legal endeavor, as NWE's draft contracts typically contain numerous unreasonable or even absurd provisions by which "[NWE], at its sole discretion, terminate this agreement." Commission oversight of the arbitrary contract provisions put forth by Northwestern would be helpful.

III. MARKET PRICE FORECASTING METHODS

(a) Is the Commission's current practice of blending forward market price information and EIA's long-term reference case forecasts reasonable? If not, what changes do you recommend and why?

LEO and Hydrodynamics direct the Commission's attention to comments on possible flaws in the Commission's current QF-1 avoided cost methodology discussed above in Section I. In addition, the question does not address the issue of "reasonable as compared to what alternatives?" It also depends on the use of which EIA forecast is utilized and which forward price market prices are "blended." QFs have raised questions about the selection of the EIA base case forecast and the method of calculating forward electricity prices and natural gas prices in past QF-1 proceedings. These potential criticisms have been previously rejected, but should be reconsidered by the Commission.

(b) Should the Commission consider a range of possible future prices (as opposed to a single price forecast) when estimating avoided costs and setting rates? If so, what sources should the Commission look to for alternative price forecasts and how should the

Commission treat the multiple forecasts in the rate setting process (e.g., should they be averaged or weighted)?

LEO and Hydrodynamics believe that more sources of potential data would provide a range of potential future electric price forecasts, each of which is dependent on different assumptions. This would assist the Commission in determining the reasonableness of the price forecasts utilized by utilities in proposing avoided costs.

(c) Since forward market prices can change, sometimes significantly, over short periods of time, would an average of recent forward price information be preferable as a starting point for developing a price forecast than a "snap- shot" taken at a particular point in time? Why or why not?

LEO and Hydrodynamics believe the use of a "snap shot" approach would lead to a significant risk of error. Average prices which level out the highs and lows in the forecasts is more likely to come up with a reasonable approximation of forward prices.

(d) Is the Commission's current approach to accounting for estimates of the incremental costs of CO2 emissions in long-term standard rates for small QFs reasonable? If not, why and how should the approach be modified?

LEO and Hydrodynamics believe the Commission's approach does not really account for C02 emissions in long-term standard rates for QFs. NWE's position from Docket D2014.1.5 was that they would negotiate for avoided C02 costs. LEO and Hydrodynamics note this was not the approach that NWE took in acquiring the PPLM hydroelectric facilities, where approximately 30 percent of the acquisition price had to do with avoided C02 costs. This approach violates 18 C.F.R. § 292.304(a) in that it is a discriminatory approach to QF ratemaking, and 18 C.F.R. § 292.304(d), which requires calculation of total avoided costs from the date the obligation is incurred. NWE has taken the position, and the Commission has agreed, that C02 costs were too uncertain to be fairly calculated in avoided cost rates and thus ratepayers should not have to pay for avoided C02 costs in light of this uncertainty. LEO and Hydrodynamics note this uncertainty did not preclude NWE from proposing, or the Commission included, avoided C02 costs in ratepayer bills.

(e) Should NWE receive all or a portion of the renewable energy credits produced by a QF if the purchase rate includes the incremental cost of CO2 emissions?

LEO and Hydrodynamics believe renewable energy credits ("RECs") account for different renewable attributes than avoided carbon costs. This why the Clean Power Plan contemplates the creation of state and federal exchanges by which carbon credits may be exchanged. RECs in contrast are to enable utilities to meet state mandates for the acquisition of a certain amount of renewable power. These are simply different programs.

(f) Is a forecast of regional (e.g., Mid-Columbia) market prices, alone, a reasonable basis for standard avoided cost rates? Why or why not?

LEO and Hydrodynamics believe it could potentially be, again depending on the forecast chosen, the length of the forecast, the liquidity of the forecast, and how transparent the forecast utilized is to interested parties.

IV. RESOURCE CAPACITY ADDITIONS

(a) Is the current practice of setting standard rates for wind QFs based on an assumed five percent capacity value reasonable? If not, why?

There should be a re-examination of this decision. Better information and studies since the 5 percent capacity contribution determination have been produced, and the basis for this determination should be revisited.

(b) Can the Commission set reasonable standard rates without calculating technology-specific capacity values using estimation methods such as effective load carrying capability or exceedance? If so, how? Are there reputable sources of estimates of average capacity values for various generating technologies that, although not specific to NWE's system, could be used for setting standard rates? If so, please identify such sources.

LEO and Hydrodynamics believe that non-NWE resource capacity value approaches and studies exist, particularly at places like National Renewable Energy Laboratory and elsewhere.

(c) Should QFs, whether or not they are eligible for standard rates, be required to contractually commit to provide a quantity of capacity in order to receive a capacity payment, with penalties or rate reductions if delivered capacity falls short? How could the Commission align such a requirement with FERC rules requiring consideration of the aggregate value of QF capacity? See 18 C.F.R. § 292.304(e).

LEO and Hydrodynamics believe estimated capacity costs, to the extent they contribute capacity value to the utility, must be part of avoided cost rates. Attempt to adjust those rates over the length of an existing QF contract would violate PURPA and Montana law.

(d) Can the Commission set reasonable QF rates absent technology-specific information regarding integration requirements and costs? If so, how?

LEO and Hydrodynamics believe different resources will likely impose and contribute different integration costs and benefits to a utility's system. However, this question needs close study.

(e) Are there reputable sources of estimates of the average integration requirements for various generating technologies that could be used for setting standard rates? If so, please identify such sources.

LEO and Hydrodynamics are unaware of the existence of such studies, but presume they must exist.

V. REQUIREMENTS FOR CREATING A "LEGALLY ENFORCEABLE OBLIGATION"

(a) Are the Commission's requirements for creating a LEO reasonable? If not, identify and explain any needed changes.

If the Commission is referring to the final order on remand in Docket D2002.8.100, no the requirement for creation of a LEO is not reasonable. The cost to sign an interconnection study for projects larger than 20 MWs is quite substantial. It is a substantial barrier to amicable contract formation. Instead, the Commission should require utilities to negotiate with prospective QFs. Poorly designed or under-financed QFs will be unable to complete their obligations to deliver power, subject to contractual penalties and other guarantees of performance. Requiring a substantial up-front investment of capital to complete transmission studies prior to even the commencement of negotiations is an unfair and unreasonable financial burden to impose on QFs.

(b) Do a QF's rights to bilaterally negotiate and create a LEO weaken, or render ineffective, the competitive bidding rule? Why or why not?

It depends on whether the utility fairly and fully implements the competitive solicitation requirements of A.R.M. § 38.5.1902(5). In the past, the utility has tended to ignore this requirement, as well as using legal and other pretexts to acquire its own resources at the expense of QFs who waited for years for either such a competitive solicitation or for NWE to negotiate. As FERC's ruling in *Hydrodynamics* makes clear, if NWE is not holding a competitive solicitation, the utility must agree to negotiate with a QF.

(c) Should the Commission consider repealing the competitive solicitation rule? Why or why not?

LEO and Hydrodynamics believe the rule in its present form should be repealed to reflect NWE's own resource acquisition practices. NWE should be required to negotiate in good faith with all prospective QFs, who should have a reciprocal obligation. NWE has shown no interest in holding competitive solicitations required by A.R.M. § 38.5.1902(5), and QFs cannot be held hostage to a process that NWE does not hold.

(d) If a utility has issued a competitive solicitation for energy or capacity that is open to QFs, would it be reasonable for LEO determinations made after issuance of the solicitation to assume that the solicited resources will be added to the utility's resource portfolio as a result of the solicitation process? Why or why not?

LEO and Hydrodynamics are unsure as to the import of this question. If the question is asking whether a solicitation accepted by both the generator and the utility should be considered an "unavoidable resource," the answer depends on the resource. However, until the resource acquisition is completed, it should continue to be avoidable rather than on the basis of a mere solicitation proposal. Also, obviously avoided costs should reflect the systemic effect on NWE's overall avoided costs, and it should reflect resource specific adjustments to account for the characteristics of the particular generator.

(e) If you answered "yes" to part (d), discuss the implications of that assumption for estimating avoided costs

N/A.

RESPECTFULLY SUBMITTED THIS 23RD DAY OF OCTOBER, 2015

UDA LAW FIRM, P.C.
By: ____________________
Michael J. Uda
Attorney for Commenters
LEO Wind, LLC and
Hydrodynamics, Inc.

CERTIFICATE OF SERVICE

I hereby certify an original was e-filed, and one copy of the foregoing were hand-delivered to the following on this 23rd day of October 2015.

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COMMENTS OF HYDRODYNAMICS INC

We hope the Commission will kindly consider our comments as we are an active developer in the State. We currently operate 5,000 kW of hydroelectric in Montana, and 29,000 kW in California.

Hydroelectric projects must obtain a license or exemption from the Federal Energy Regulatory Commission. This is a process which can take years to complete at significant expense. All hydroelectric projects are unique and thus major equipment must be tailored to the individual project. This results in lead times that can be greater than 12 months to obtain a turbine and generator. The purchase of such equipment cannot be done until a license and a Power Purchase Agreement are obtained. Interconnection studies can also be lengthy and expensive. It is difficult to balance the risk of these expenses without obtaining a sales contract on the outset. A Power Purchase Agreement is a key component in the early stages of project development, not the last step after significant capital expense. The current process with Northwestern requires developers to expend large amounts of time, money and effort prior to obtaining a contract. After which, a contract may no longer be available, once "[Northwesterns] need for QF energy is satisfied."

We feel draft contracts should be offered to any party on request, and that contract negotiations should continue with all hydro projects regardless of their position in a 'queue'. A commission review of each contract, could expedite the process. Contract negotiation is no small legal endeavor, as Northwestern's draft contracts contain numerous unreasonable or even absurd provisions by which "Northwestern may, at its sole discretion, terminate this agreement." Commission oversight of the arbitrary contract provisions put forth by Northwestern would be helpful. We also feel a 50MW contracting limit is inappropriately low and should be discontinued.

Small scale hydropower is more easily integrated and reliable. Hydropower should be pursued to provide a more balanced mix of renewables in the State. Distributed generation also serves to help regulate voltage and improve system reliability in rural areas.

Exhibit 1

Idaho has far better QF rates; however the transmission lines to Idaho are contractually full. Only the large projects seem to be able to obtain transmission, leaving many projects with Northwestern as their sole potential customer.

A PPA needs to be in place, before the financial risk of developing a FERC license can be accepted. The FERC licensing process needs to be advancing well, or completed, before funding interconnect and transmission. An Interconnect contract requires Site Control to proceed. Land rights are another expense that should be paid after obtaining a PPA. We also have a concern this could cause a project to lose its position in Northwester's supply contracting queue, because it is waiting in the Northwestern Interconnection queue.

Until the FERC license is granted, the size of the project is uncertain, the suppliers that are going to be competitive are unknown, and the specific characteristics of the equipment needed for the interconnect studies are only estimates since the equipment is likely to change upon issuance of the FERC license. Then with the actual equipment selections made, the studies have to be paid for and performed again.

In summary, Northwestern Energy should start with a reasonable contract proposal and execute reasonable contracts immediately that allow for development of all other aspects of a project, especially in the case of the extra effort required for hydro projects.

Respectfully,

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